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CRUDE OIL FLOW BEHAVIOURS OF DEEP WATER EASTCOAST FIELD IN PRODUCTION LINES BY USING SIMULATION STUDIES

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Abstract

This project presentsFlow assurance refers to ensuring successful and economical flow of hydrocarbon stream from reservoir to the reception facilities and is closely linked to multiphase flow technology. Flow assurance studies include all the issues important to maintaining the flow of oil & gas and must consider the capabilities and requirements for all parts of the system throughout the entire life of the system. An engineering process works with an objective to maximize production by ensuring unrestricted production flow path throughout the field life with lifecycle cost at minimum.

KEY WORDS: Flow lines, Fluid characteristics, Flow Technology.

1. INTRODUCTION

Flow assurance refers to ensuring successful and economical flow of hydrocarbon stream from reservoir to the reception facilities and is closely linked to multiphase flow technology. Flow assurance studies include all the issues important to maintaining the flow of oil & gas and must consider the capabilities and requirements for all parts of the system throughout the entire life of the system. An engineering process works with an objective to maximize production by ensuring unrestricted production flow path throughout the field life with lifecycle cost at minimum.Subsea oil field developments are usually split into shallow water and deep water categories to distinguish between the different facilities and approaches that are needed.

Deepwater is a term often used to refer to offshore projects located in water depths greater than around 1500 to 2000m sea water depth, where floating drilling vessels and floating oil platforms are used, and unmanned underwater vehicles are required as manned diving is not practical. Recently, all subsea solutions are also considered in shallow water fields as they can compete with floating platforms in cost and reliability

2. Literature review

3.CASE STUDY

The case study involves 6 wells viz. X2, X2 A, X2 B, X2 C, X2 D, X2 E which lies which spread over an area of 7200 sq.km in water depths ranging from 250 meters to 800 meters. The depth of the wells ranges from around 1400 meters to 1700 meters. Fluid characteristics of the oil indicate high pour point crude with wax content of 17-21%. In view of the poor oil characteristics, low ambient temperatures and lower reservoir energy theoption of subsea tieback to FPSO in close proximity to the oil fields has evolved technically tobe the most feasible development option.

3.1Design Layout: Well Co-ordinates

The given well co-ordinate profiles and their respective depths for the case study involving 6 wells are mentioned below.

Well	X	Y	Water depth (m)	Well depth(m)
X-2	644242.20	1805595.90	610	1625
X-2-A	644322.55	1805081.33	630	1570
X-2-B	645607.94	1803587.73	720	1480
X-2-C	646246.88	1803959.47	730	1470
X-2-D	643297.72	1805006.81	600	1600
X-2-E	641677.69	1807101.91	530	1670
FPSO 2	640800	1809200	350	

Table 4.3.1: Well coordinates, Water depth, Well Depth

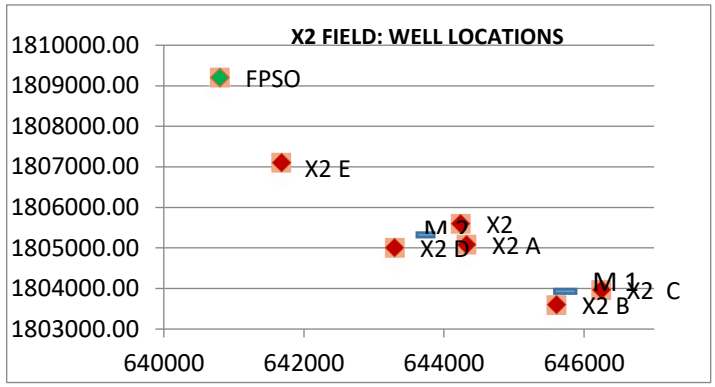

Figure 4.3.2: Well locations

4.4 Production Profiles:

Detailed well wise pressure production profiles are placed below

Year	Oil rate	Gas rate	Water rate	Liquid Rate	GOR	WC	Cum Oil	Cum Gas	Avg Res P	FBHP
	m3/d	MMm3/d	m3/d	m3/d	v/v	%	MMm3	MMm3	Ksc	Ksc
									260.5	
2019-20	417	0.048	0.0	417	116	0.0	0.15	18	246.8	238.9
2020-21	988	0.165	12.3	1000	167	1.2	0.51	78	225.1	205.8
2021-22	957	0.149	42.7	1000	156	4.3	0.86	132	208.6	184.2
2022-23	943	0.148	57.1	1000	157	5.7	1.21	186	192.4	164.4
2023-24	850	0.132	150.4	1000	156	15.0	1.52	235	174.6	137.5
2024-25	696	0.153	303.7	1000	220	30.4	1.77	291	154.7	110.7
2025-26	563	0.219	437.1	1000	390	43.7	1.98	371	130.7	82.3
2026-27	435	0.313	541.8	976	719	55.5	2.13	485	104.9	60.0
2027-28	252	0.325	453.9	706	1290	64.3	2.23	603	88.9	60.0
2028-29	133	0.261	343.1	476	1960	72.1	2.28	699	79.4	60.0
2029-30	85	0.221	257.7	343	2602	75.2	2.31	779	73.3	60.0
2030-31	58	0.180	188.2	246	3125	76.6	2.33	845	69.1	60.0

Table 4.4.1: X2 PRODUCTION PROFILE

Year	Oil rate	Gas rate	Water rate	Liquid Rate	GOR	WC	Cum Oil	Cum Gas	Avg Res P	FBHP
	m3/d	MMm3/d	m3/d	m3/d	v/v	%	MMm3	MMm3	Ksc	Ksc
									260.5	
2019-20	417	0.05	0.0	417	113	0.0	0.15	17	246.5	239.4
2020-21	873	0.09	127.1	1000	105	12.7	0.47	51	224.7	209.0
2021-22	634	0.06	366.4	1000	96	36.6	0.70	73	207.8	185.7
2022-23	543	0.05	457.4	1000	90	45.7	0.90	91	192.0	167.1
2023-24	503	0.04	496.8	1000	87	49.7	1.08	107	174.3	145.1
2024-25	488	0.06	512.1	1000	118	51.2	1.26	128	152.8	116.3
2025-26	518	0.10	482.0	1000	187	48.2	1.45	163	127.2	81.0
2026-27	461	0.22	429.3	890	484	48.2	1.62	244	102.3	60.0
2027-28	278	0.28	254.9	533	1024	47.8	1.72	348	86.6	60.0
2028-29	200	0.21	168.1	369	1053	45.6	1.79	425	78.1	60.0
2029-30	162	0.17	113.0	275	1022	41.1	1.85	485	72.8	60.0
2030-31	131	0.14	75.4	207	1044	36.5	1.90	535	69.0	60.0

Table 4.4.2: X2 A PRODUCTION PROFILES

Year	Oil rate	Gas rate	Water rate	Liquid Rat	GOR	WC	Cum Oil	Cum Gas	Avg Res P	FBHP
	m3/d	MMm3/d	m3/d	m3/d	v/v	%	MMm3	MMm3	Ksc	Ksc
									260.5	
2019-20	417	0.05	0.0	417	109	0.0	0.15	17	237.3	220.7
2020-21	1000	0.10	0.0	1000	98	0.0	0.52	52	206.9	176.9
2021-22	1000	0.09	0.0	1000	91	0.0	0.88	86	181.7	145.5
2022-23	996	0.10	4.4	1000	99	0.4	1.25	122	155.3	103.8
2023-24	923	0.20	24.5	948	215	2.6	1.58	194	122.4	60.0
2024-25	591	0.21	37.6	628	361	6.0	1.80	272	107.1	60.0
2025-26	387	0.15	96.9	484	392	20.0	1.94	327	99.7	60.0
2026-27	286	0.12	171.4	457	406	37.5	2.04	370	93.7	60.0
2027-28	202	0.12	172.2	374	578	46.1	2.12	412	85.1	60.0
2028-29	129	0.12	131.0	260	897	50.4	2.16	454	76.5	60.0
2029-30	77	0.10	89.2	166	1292	53.6	2.19	491	69.3	60.0
2030-31	42	0.07	57.5	100	1753	57.6	2.21	518	64.5	60.0

Table 4.4.3: X2 B PRODUCTION PROFILES

Year	Oil rate	Gas rate	Water rate	Liquid Rate	GOR	WC	Cum Oil	Cum Gas	Avg Res Pr	FBHP
	m3/d	MMm3/d	m3/d	m3/d	v/v	%	MMm3	MMm3	Ksc	Ksc
									260.5	
2019-20	333	0.04	0.0	333	114	0.0	0.12	14	248.8	239.5
2020-21	758	0.08	42.5	800	107	5.3	0.40	43	233.4	215.6
2021-22	607	0.06	193.1	800	103	24.1	0.62	66	229.0	198.4
2022-23	526	0.05	273.6	800	101	34.2	0.81	86	224.9	193.2
2023-24	493	0.05	306.5	800	99	38.3	0.99	104	218.8	186.3
2024-25	468	0.04	331.6	800	96	41.4	1.16	120	209.7	175.5
2025-26	445	0.04	355.3	800	92	44.4	1.33	135	199.5	162.7
2026-27	421	0.04	379.1	800	89	47.4	1.48	148	188.4	147.2
2027-28	404	0.04	396.4	800	90	49.5	1.63	162	176.8	132.8
2028-29	402	0.04	398.3	800	96	49.8	1.77	176	165.7	117.5
2029-30	372	0.09	427.5	800	234	53.4	1.91	208	152.7	100.7
2030-31	334	0.12	466.3	800	361	58.3	2.03	251	138.2	85.5

Table 4.4.6: X2 E PRODUCTION PROFILES

Year	Oil rate	Gas rate	Water rate	Liquid Rat	GOR	WC	Cum Oil	Cum Gas	Avg Res P	FBHP
	m3/d	MMm3/d	m3/d	m3/d	v/v	%	MMm3	MMm3	Ksc	Ksc
									260.5	
2019-20	417	0.05	0.0	417	108	0.0	0.15	16	232.6	221.5
2020-21	1000	0.10	0.0	1000	95	0.0	0.52	51	201.4	182.3
2021-22	1000	0.09	0.0	1000	90	0.0	0.88	84	175.1	149.4
2022-23	1000	0.12	0.0	1000	123	0.0	1.25	129	144.2	111.4
2023-24	1000	0.20	0.0	1000	196	0.0	1.61	200	104.4	62.8
2024-25	694	0.18	10.4	705	257	1.5	1.87	265	90.1	60.0
2025-26	344	0.09	174.7	518	264	33.7	1.99	299	94.0	60.0
2026-27	246	0.10	253.9	500	387	50.7	2.08	333	89.9	60.0
2027-28	170	0.11	227.5	397	669	57.3	2.14	375	82.2	60.0
2028-29	98	0.12	157.6	255	1250	61.7	2.18	420	74.0	60.0
2029-30	56	0.10	104.3	160	1722	65.2	2.20	455	67.9	60.0
2030-31	32	0.06	66.3	98	1968	67.7	2.21	477	64.2	60.0

Table 4.4.4: X2 C PRODUCTION PROFILES

Year	Oil rate	Gas rate	GOR	Water rate	WC	Cum Oil	Cum Gas	Cum Water
	m3/d	MMm3/d	v/v	m3/d	%	MMm3	MMm3	MMm3
2019-20	2417	0.27	112	0	0	0.88	99	0.00
2020-21	5618	0.63	112	182	3	2.93	329	0.07
2021-22	5198	0.55	105	602	10	4.83	528	0.29
2022-23	5008	0.57	113	792	14	6.66	735	0.58
2023-24	4769	0.78	163	978	17	8.40	1018	0.93
2024-25	3938	0.84	214	1195	23	9.84	1326	1.37
2025-26	3246	0.94	288	1546	32	11.02	1668	1.93
2026-27	2496	1.16	463	1779	42	11.93	2090	2.58
2027-28	1624	1.11	681	1574	49	12.52	2494	3.16
2028-29	1142	0.88	773	1330	54	12.94	2816	3.64
2029-30	864	0.74	857	1155	57	13.26	3086	4.06
2030-31	670	0.61	912	1002	60	13.50	3309	4.43

Tables 4.4.7: COMPOSITE PRODUCTION PROFILES(X2, X2 A, X2 B, X2 C, X2 D, X2 E)

Year	Oil rate	Gas rate	Water rate	Liquid Rat	GOR	WC	Cum Oil	Cum Gas	Avg Res P	FE
	m3/d	MMm3/d	m3/d	m3/d	v/v	%	MMm3	MMm3	Ksc	K
									260.5	
2019-20	417	0.05	0.0	417	111	0.0	0.15	17	240.6	23
2020-21	1000	0.10	0.0	1000	101	0.0	0.52	54	218.3	20
2021-22	1000	0.09	0.0	1000	93	0.0	0.88	87	200.1	18
2022-23	1000	0.09	0.0	1000	94	0.0	1.25	122	183.4	16
2023-24	1000	0.16	0.0	1000	157	0.0	1.61	179	160.1	13
2024-25	1000	0.20	0.0	1000	197	0.0	1.98	251	135.2	10
2025-26	990	0.34	0.0	990	340	0.0	2.34	374	98.4	6
2026-27	647	0.37	3.7	651	576	0.6	2.57	510	90.3	6
2027-28	319	0.23	68.9	388	722	17.7	2.69	594	87.4	6
2028-29	180	0.13	131.9	312	746	42.2	2.76	643	82.4	6
2029-30	112	0.07	163.6	275	634	59.4	2.80	669	76.9	6
2030-31	74	0.04	148.2	222	514	66.8	2.82	682	72.0	6

Table 4.4.5: X2 D PRODUCTION PROFILES

4.5Bathymetry/Ambient Temperatures

Water depth-meters	5	50	100	200	280	500	700	1000	>1000
Temperature ^{0}C (min/max)	27/30	24/30	19/27	13/16	11/13	7	6	5	4

Table 4.5 Sea bed temperature with respect to water depth increase is tabulated below.

4.6 Infield distances between wells

The infield distances between the well locations as per coordinates with the likely X, Y coordinates of the FPSO location assumed 640800.00, 1809200.00.

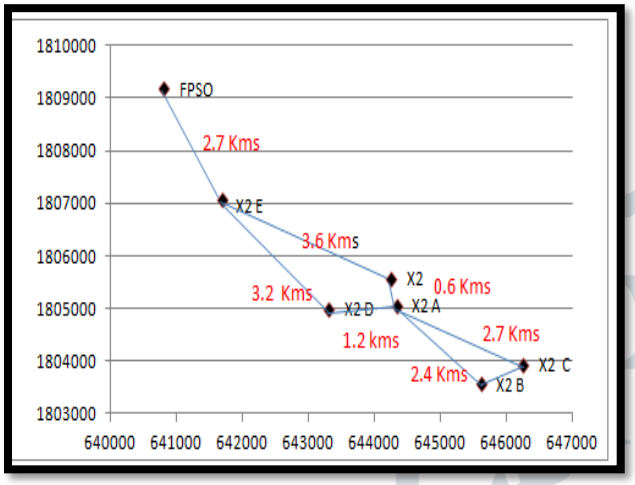

Figure 4.6.1: Infield Distances

Infield distances as per coordinates		
TO	FROM	DISTANCES
X2	X2 A	0.6
	X2 B	2.9
	X2 C	3.1
	X2 D	1.3
	X2 E	3.6
X2 A	X2 B	1.2
	X2 C	4.0
	X2 D	2.4
	X2 E	2.7
X2 B	X2 C	O.9
	X2 D	3.3
	X2 E	6.3
X2 C	X2 D	3.8
	X2 E	6.7
X2 D	X2 D	3.2

Table 4.6.1: Infield distances s per co-ordinate

4.7 Fluid Characteristics: The live fluid characteristics are represented below and form the basis of the study.

Crude characteristics	
Reservoir Temp ℉	260
WAT-0C	47
Pour point-0C	36
API gravity	35.12
Specific Gravity	0.8528
Wax Content	21.93%

Table 4.7: Fluid characteristics

4.8 METHODOLOGY OF STUDY

The following studies were carried out and detailed below in individual sections:

I. Vertical Lift Performance for Tubing size selection

II. Thermo Hydraulic analysis for selection of flow line size, type and insulation

III. Artificial lift requirement

IV. Bean size selection

Multiphase flow simulator PIPESIM has been used for steady state flow hydraulics.

4.8.1 VERTICAL LIFT PERFORMANCE FOR TUBING SIZE SELECTION

In nodal analysis there are curves for inflow (IPR) and out flow (Vertical Lift Performance). Vertical lift performance is representing how the fluid flows inside the tubing that would create a specific trend of pressure drops along the conduit..

Vertical lift performance analysis has been carried out considering tubing sizes of 3.5”, 4.5” & 5.5” for each well as per the production profiles. All wells have been considered as vertical and Vogel’s IPR is been considered for the purpose of study. Simulation studies were performed using the black oil model developed in PIPESIM with the standard correlations.

The following factors have been considered for optimization of tubing size for the oil wells.

- Pressure and Temperature drop across the tubing.
- Erosional Velocity Ratio

The System Outlet Pressure, System Outlet Temperature, Emotional Velocity Ratio for the wells generated from the simulation is tabulated below.

NOTE: Red fonts indicates EVR exceeds 1 (EVR>1)

Table 4.8.1.A THP & THT For X2 well

	3 1/2				4 1/2				5 1/2			
Year	Sys Out P	Sys Out T	EVR	MV(O/L)	Sys Out P	Sys Out T	EVR	MV(O/L)	Sys Out P	Sys Out T	EVR	MV(O/L)
	Ksc	°C			Ksc	°C			Ksc	°C		
2019-20	126.7	126.7	0.3	1.7	128.1	48.6	0.2	1.2	128.7	45.45	0.1	0.6
2020-21	98.5	98.8	1.0	5.9	109.0	55.3	0.7	3.9	114.8	53.70	0.4	2.0
2021-22	79.3	83.5	1.0	6.3	90.2	55.8	0.7	4.1	95.9	54.19	0.4	2.0
2022-23	63.7	70.7	1.1	7.1	76.2	55.9	0.8	4.5	82.2	54.40	0.4	2.2
2023-24	40.0	54.1	1.3	8.3	54.7	57.4	0.8	4.9	61.9	55.97	0.4	2.4
2024-25	16.6	37.6	2.2	13.1	36.5	59.4	1.1	6.6	50.0	58.12	0.5	3.1
2025-26		14.4	6.8	44.4	13.9	60.5	2.1	12.9	34.6	59.36	0.7	4.7
2026-27			7.1	373.9		61.0	8.6	38.5	18.4	59.98	1.2	9.1
2027-28			6.7	1062.6	5.9	60.1	3.4	34.2	24.0	58.90	0.9	9.8
2028-29		10.2	6.9	70.2	15.6	58.6	1.7	22.1	26.7	57.06	0.7	8.0
2029-30	11.2	16.9	2.2	37.1	20.7	56.8	1.2	17.1	28.4	54.90	0.5	7.0
2030-31	18.0	21.6	1.4	23.7	24.3	54.5	0.8	13.0	30.1	52.09	0.4	5.7

Table 4.8.1.B: THP & THT For X2 A well

	3 1/2				4 1/2				5 1/2			
Year	Sys Out P	Sys Out T	EVR	MV(O/L)	Sys Out P	Sys Out T	EVR	MV(O/L)	Sys Out P	Sys Out T	EVR	MV(O/L)
	Ksc	°C			Ksc	°C			Ksc	°C		
2019-20	129.8	50.8	0.3	1.6	131.1	49.3	0.2	1.1	131.7	46.2	0.1	0.6
2020-21	88.4	59.3	0.8	4.5	96.1	58.6	0.6	3.0	100.4	57.0	0.3	1.5
2021-22	59.9	62.2	0.9	4.5	67.1	61.6	0.6	3.0	71.2	60.2	0.3	1.5
2022-23	41.4	63.0	0.9	4.9	48.7	62.3	0.6	3.2	52.6	61.0	0.3	1.6
2023-24	24.4	63.0	1.1	5.8	32.6	62.4	0.7	3.6	36.5	61.1	0.4	1.8
2024-25	11.4	62.8	1.6	8.8	23.3	62.2	0.9	4.7	29.3	61.0	0.4	2.3
2025-26		62.1	5.1	21.4	10.5	61.5	1.5	7.8	24.1	60.3	0.6	3.3
2026-27			6.9	203.8	0.4	60.5	6.4	20.2	20.3	59.3	0.9	6.2
2027-28		58.3	7.7	56.0	15.0	57.8	1.8	19.7	27.4	56.3	0.7	7.4
2028-29	11.6	56.1	2.1	27.4	21.4	55.3	1.1	13.8	29.7	53.3	0.5	5.7
2029-30	18.5	53.6	1.3	18.6	25.0	52.6	0.8	10.5	31.0	50.1	0.4	4.6
2030-31	22.7	50.8	0.9	14.1	27.6	49.5	0.6	8.4	32.1	46.5	0.3	3.8

Table 4.8.1.C: THP & THT For X2 B well

	3 1/2				4 1/2				5 1/2			
Year	Sys Out P	Sys Out T	EVR	MV(O/L)	Sys Out P	Sys Out T	EVR	MV(O/L)	Sys Out P	Sys Out T	EVR	MV(O/L)
	Ksc	°C			Ksc	°C			Ksc	°C		
2019-20	118.7	51.5	0.3	1.7	120.0	50.1	0.2	1.2	120.6	47.0	0.1	0.6
2020-21	71.9	57.1	0.9	5.5	79.4	56.4	0.6	3.6	83.5	54.8	0.3	1.8
2021-22	47.8	56.1	1.0	6.9	56.1	55.5	0.7	4.2	60.3	53.9	0.3	2.1
2022-23	19.9	55.8	1.5	11.0	32.6	55.3	0.9	5.8	39.3	53.8	0.4	2.7
2023-24		55.6	6.7	68.3	7.2	55.5	2.5	14.9	24.3	54.4	0.7	5.1
2024-25	1.9	54.7	5.1	26.7	17.6	54.3	1.4	12.1	29.3	52.7	0.6	4.8
2025-26	10.9	55.4	1.9	16.0	20.5	54.6	1.0	8.5	29.6	52.7	0.4	3.6
2026-27	10.4	57.1	1.6	15.3	18.9	56.3	0.9	7.9	27.8	54.2	0.4	3.3
2027-28	14.2	56.7	1.3	15.5	21.4	55.7	0.8	8.3	29.1	53.6	0.4	3.5
2028-29	20.3	54.5	1.0	13.2	25.6	53.3	0.6	7.7	31.5	50.7	0.3	3.4
2029-30	25.3	50.9	0.7	10.2	29.2	49.5	0.4	6.3	33.0	46.3	0.2	2.9
2030-31	29.0	45.8	0.4	7.0	31.4	44.0	0.3	4.5	34.9	40.4	0.1	2.1

	3 1/2				4 1/2				5 1/2			
Year	Sys Out P	ys Out	EVR	MV(O/L)	Sys Out P	ys Out	EVR	MV(O/L)	Sys Out P	ys Out	EVR	MV(O/L)
	Ksc	°C			Ksc	°C			Ksc	°C		
2019-20	119.7	51.5	0.3	1.6	121.0	50.1	0.2	1.2	121.5	47.0	0.1	0.6
2020-21	75.5	57.2	0.9	5.1	82.8	56.5	0.6	3.4	86.8	54.9	0.3	1.7
2021-22	50.8	56.1	1.0	6.3	58.6	55.5	0.7	4.0	62.8	53.9	0.3	2.0
2022-23	28.7	55.9	1.5	11.5	42.4	55.5	0.9	6.1	49.6	54.0	0.4	2.9
2023-24			17.8	299.5	8.4	55.3	2.3	19.2	26.2	54.2	0.7	5.8
2024-25		54.4	5.8	46.0	15.5	54.0	1.4	14.7	27.9	52.4	0.6	5.2
2025-26	7.1	57.5	1.8	12.3	16.0	56.7	0.9	6.4	25.6	54.7	0.4	2.7
2026-27	6.5	59.1	1.9	15.2	15.5	58.3	0.9	7.5	25.1	56.4	0.4	3.0
2027-28	12.1	58.2	1.5	16.0	19.7	57.3	0.8	8.4	27.9	55.3	0.4	3.4
2028-29	21.3	55.5	1.0	13.2	26.5	54.4	0.6	7.8	31.8	51.9	0.3	3.5
2029-30	26.8	51.7	0.6	9.2	30.2	50.3	0.4	5.8	34.0	47.2	0.2	2.7
2030-31	29.6	46.2	0.4	5.6	31.7	44.4	0.3	3.7	35.9	40.7	0.1	1.7

Table 4..8.1.D: THP & THT For X2 C well

	3 1/2				4 1/2				5 1/2			
Year	Sys Out P	ys Out	EVR	MV(O/L)	Sys Out P	ys Out	EVR	MV(O/L)	Sys Out P	ys Out	EVR	MV(O/L)
	Ksc	°C			Ksc	°C			Ksc	°C		
2019-20	122.1	50.3	0.3	2	123.5	48.8	0.2	1.2	124.0	45.7	0.1	0.6
2020-21	87.9	56.6	0.9	5	95.8	55.9	0.6	3.2	100.2	54.2	0.3	1.6
2021-22	69.2	56.2	0.9	5	77.0	55.5	0.6	3.4	81.2	53.8	0.3	1.7
2022-23	54.8	55.1	1.0	6	63.2	54.5	0.7	3.8	67.6	52.8	0.3	1.9
2023-24	42.5	55.2	1.4	10	57.9	54.8	0.9	5.7	65.6	53.3	0.4	2.7
2024-25	18.0	54.9	2.3	20	39.1	54.7	1.1	8.7	53.5	53.4	0.5	3.7
2025-26			7.2	351		54.4	9.1	36.4	23.2	53.7	1.0	9.0
2026-27		53.2	7.4	145	12.2	53.3	2.5	25.7	28.5	52.2	0.9	8.8
2027-28	11.6	53.3	2.2	22	22.2	52.5	1.1	11.7	30.7	50.5	0.5	5.0
2028-29	15.3	54.2	1.3	14	22.1	53.1	0.8	7.7	29.2	50.6	0.4	3.4
2029-30	13.5	54.5	0.9	9	19.4	53.3	0.5	5.3	26.4	50.5	0.2	2.2
2030-31	15.1	53.0	0.6	6	20.1	51.5	0.3	3.2	25.4	48.4	0.2	1.4

Table 4.8.1.E: THP & THT For X2 D well

	3 1/2				4 1/2				5 1/2			
Year	Sys Out P	ys Out	EVR	MV(O/L)	Sys Out P	ys Out	EVR	MV(O/L)	Sys Out P	ys Out	EVR	MV(O/L)
	Ksc	°C			Ksc	°C			Ksc	°C		
2019-20	128.9	47.9	0.3	1.3	129.8	46.3	0.2	0.9	130.0	42.8	0.1	0.5
2020-21	100.9	55.7	0.7	3.6	104.4	55.9	0.5	2.4	108.9	52.7	0.2	1.3
2021-22	86.7	55.7	0.7	3.6	83.5	59.0	0.5	2.4	94.6	52.7	0.3	1.3
2022-23	82.3	55.6	0.7	3.6	75.1	60.3	0.5	2.5	90.2	52.6	0.3	1.3
2023-24	76.7	55.4	0.7	3.7	67.8	60.7	0.5	2.5	84.6	52.4	0.3	1.3
2024-25	68.3	55.2	0.7	3.9	58.1	60.9	0.5	2.6	76.1	52.2	0.3	1.3
2025-26	58.5	54.9	0.8	4.1	47.2	61.1	0.5	2.7	66.3	51.9	0.3	1.4
2026-27	47.6	54.5	0.8	4.4	35.8	61.3	0.5	2.9	55.8	51.6	0.3	1.5
2027-28	38.7	53.8	0.9	4.8	27.5	61.2	0.6	3.2	48.1	51.0	0.3	1.6
2028-29	30.4	53.7	1.0	5.5	21.2	61.1	0.6	3.6	42.1	51.0	0.3	1.8
2029-30	23.0	54.2	1.8	10.8	26.3	61.1	1.0	6.1	52.8	52.1	0.5	2.9
2030-31	8.3	54.2	3.8	22.4	20.1	61.3	1.5	10.5	47.1	52.8	0.6	4.3

Table 4.8.1.F: THP & THT For X2 E well

From the above tables we observe that for X2, X2A, X2 B, X2 C& X2 D wells with tubing id 31/2 & 41/2 are not showing any tubing head pressures in their mid life, hence no flow. Besides the EVR exceeds the limit of 1 in most of the cases.

Selection of the tubing will be based on these criteria:

- Flow rate (High)
- Erosion velocity ratio (<1)
- Cost (Generally increases with size)

As per the VLP study and optimized tubing size all wells indicates that major part of the profiles can be recovered as per the profile rates.

The likely THP, THT with optimum tubing size is indicated in the table below.

Year	X2	X2 A	X2 B	X2 C	X2 D	X2 E
	5 1/2	5 1/2	5 1/2	5 1/2	5 1/2	4 1/2
2019-20	129	132	121	121	124	130
2020-21	115	100	84	87	100	104
2021-22	96	71	60	63	81	84
2022-23	82	53	39	50	68	75
2023-24	62	36	24	26	66	68
2024-25	50	29	29	28	54	58
2025-26	35	24	30	26	23	47
2026-27	18	20	28	25	29	36
2027-28	24	27	29	28	31	27
2028-29	27	30	32	32	29	21
2029-30	28	31	33	34	26	26
2030-31	30	32	35	36	25	20

Table 4.8.1.H: Tubing Head Temperature for optimum tubing size

Table 4.8.1.G: Tubing Head Pressure for optimum tubing size

Year	X2	X2 A	X2 B	X2 C	X2 D	X2 E
	5 1/2	5 1/2	5 1/2	5 1/2	5 1/2	4 1/2
2019-20	45.4	46.2	47.0	47.0	45.7	46.3
2020-21	53.7	57.0	54.8	54.9	54.2	55.9
2021-22	54.2	60.2	53.9	53.9	53.8	59.0
2022-23	54.4	61.0	53.8	54.0	52.8	60.3
2023-24	56.0	61.1	54.4	54.2	53.3	60.7
2024-25	58.1	61.0	52.7	52.4	53.4	60.9
2025-26	59.4	60.3	52.7	54.7	53.7	61.1
2026-27	60.0	59.3	54.2	56.4	52.2	61.3
2027-28	58.9	56.3	53.6	55.3	50.5	61.2
2028-29	57.1	53.3	50.7	51.9	50.6	61.1
2029-30	54.9	50.1	46.3	47.2	50.5	61.1
2030-31	52.1	46.5	40.4	40.7	48.4	61.3

Summary

- The tables generated from the Vertical Lift Performance indicate that the production rates meet the major part of the production profiles with selected tubing size.
- Tubing head temperatures of oil wells are above the WAT with insulation value of 2Btu/ft2/0F/hr in the tubing except for X2 B and X2 C wells where the tubing head temperature falls below WAT in the fag end period.
- The recommended tubing size for the tubing is tabulated below.

WELLS	TUBING SIZE
X2, X2 A, X2 B, X2 C, X2 D	5.5”
X2 E	4.5”

Table 4.8.1.I: Tubing Head Temperature for optimum tubing size

4.8.2 THERMO HYDRAULIC ANALYSIS FOR SELECTION OF FLOWLINE SIZE, TYPE AND INSULATION

The methodology followed was to arrive at a hydraulic line size that will enable the flow for the entire profile period. Adequacy of the line size and insulation, to flow the well fluids so as to reach the FPSO at a temperature above the WAT, over the entire field life is studied. Similarly a sensitivity is carried out on the overall heat transfer co-efficient required for the well fluid to arrive at the FPSO above the WAT temperature with the selected line size.

The pipeline systems are found to meet the arrival temperature requirements with passive insulation so dual line configurations is considered for the purpose of analysis.

Due to the close proximity of the wells, X2 B, X2 C were grouped into one cluster and X2, X2 A, X2 B, X2 D into another cluster. Since X2 E is very near to FPSO the well is flowingdirectly to the FPSO. Flow hydraulics for the infield well fluids lines from well head to manifold and main lines for comingled fluid is from manifold to host facilities were simulated through a steady state model developed in Multiphase flow simulator PIPESIM. Two manifolds are considered. M1 for the wells X2 B and X2 C; M2 for the wells X2, X2 A and X2 D.

The integrated model developed in pipesim is shown below.

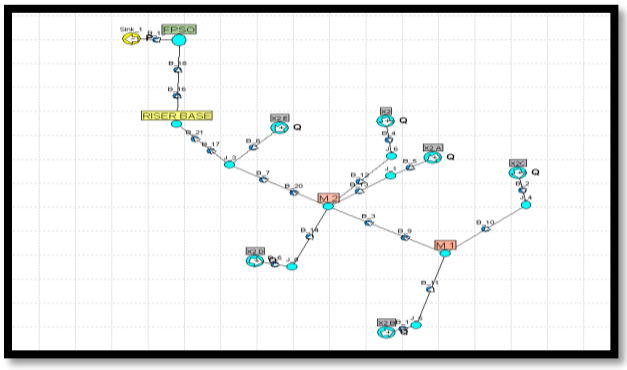

Figure 4.8.2.A: Integrated model of the X2 field developed in pipesim.

The following assumptions have been considered for oil infield flowlines.

- The arrival pressure at FPSO (inlet of separator) is 10kg/cm2
- Pour point temperature is 36℃ and live oil WAT 20C.

For carrying out the study the following bathymetry was considered in the simulation model for the flow line.

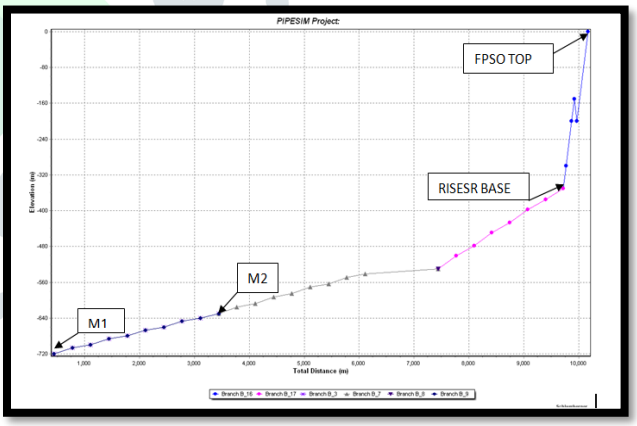

Figure 4.8.2.B: Bathymetry considered for simulation

1. Hydraulic analysis:

The flow line sizing has been carried out using dual 8”, 10”, 12” line sizes. The plot below indicates the pressure drop with various line sizes by considering

the receiving end pressure at FPSO is 10 kg/cm2 for flow line optimization from the far end to FPSO.

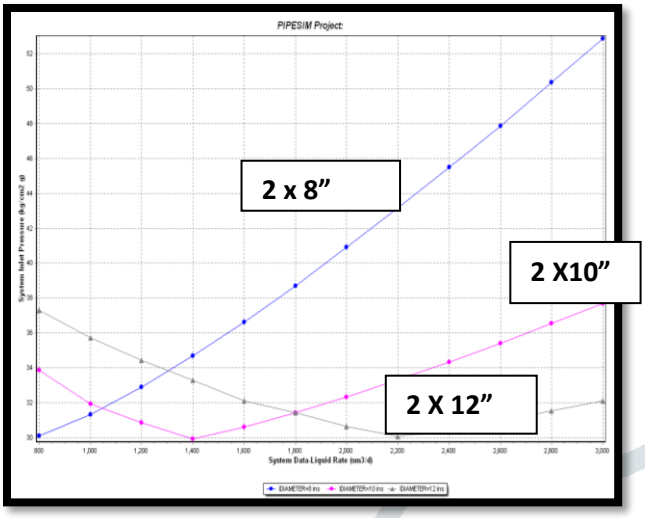

Figure 4.8.2.C: Selection of flow line ID

We determine the smallest pipeline I.D. that will allow the design flow rate to be transported from the far end manifold whilst maintaining an arrival pressure of not lower than 10 Ksc at the FPSO.From the above plot it can be observed that pressure drop in dual 10” line size is found to be optimum. So 10” size is recommended for the flow line.

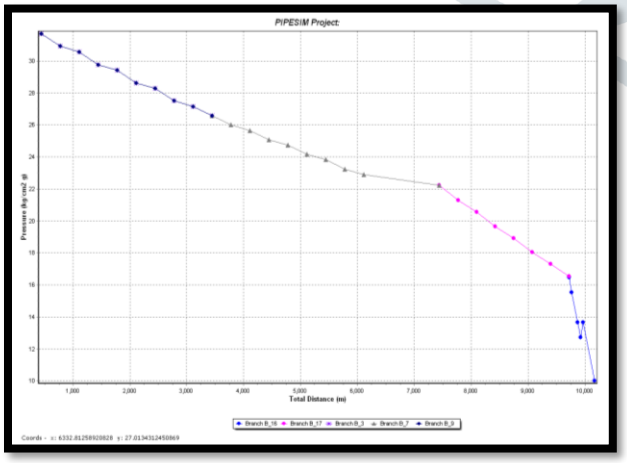

Figure 4.8.2.D: Pressure Drop from well head to FPSO

The plot above indicates the pressure drop from well head (far end) to FPSO for the selected line size 2x10”x10.1kms.

The back pressure at each well head with dual 10” flowline and considering the receiving end pressure at 10 Ksc is observed. For the flowline selected the likely after bean pressures (ABP’s) required over the profile period are tabulated below with 8” infield line/jumper from individual well head to manifolds and 2x10”x10.1kms flowline and riser from X2-M1 manifold to FPSO.

Year	X2	X2 A	X2 B	X2C	X2 D	X2 E
2019-20	25.6	25.5	30.5	30.9	25.7	21.4
2020-21	31.7	31.3	35.8	36.1	31.8	24.4
2021-22	31.6	31.2	35.9	36.2	31.7	24.2
2022-23	32.3	31.9	36.3	36.7	32.5	24.8
2023-24	32.8	32.5	36.1	36.3	33.3	24.9
2024-25	31.5	31.0	34.3	34.5	31.6	24.2
2025-26	30.7	30.1	33.6	33.9	30.6	24.0
2026-27	32.0	31.2	34.9	35.2	32.0	23.9
2027-28	29.7	29.0	32.4	32.8	29.6	21.7
2028-29	26.6	26.2	29.0	29.7	26.4	20.0
2029-30	23.8	23.5	26.0	26.9	23.6	18.8
2030-31	23.2	22.9	25.3	26.5	22.9	17.9

Table 4.8.2.A: ABP with 10 Ksc pressure at the FPSO (**Red font indicates THP<ABP**)

ARRIVAL PRESSURE AT FPSO	ARRIVAL TEMPERATURE AT FPSO
10	***43***
10	***44***
10	***45***
10	***46***
10	47

10	47
10	48
10	48
10	***46***
10	***41***
10	***41***

Table 4.8.2.B: Arrival temperature at FPSO (**Red italics indicates the FPSO temp < dead WAT)**

2 Thermal performance

Flow lines from the manifolds upto the riser base have been considered to be rigid flow lines, while flexible flow lines have been considered from the riser base to the FPSO. For the selected flow line size, the likely requirement of insulation so as to maintain the fluid temperature above WAT on arrival at FPSO have been simulated considering different U values (0.6/0.4/0.176 Btu/hr/ft2/0F. The likely temperature drop in the flow line from bottom hole to FPSO considering the peak liquid rate is indicated in the plot below. It is noticed that the FPSO receiving temperature is nearly equal to the WAT.

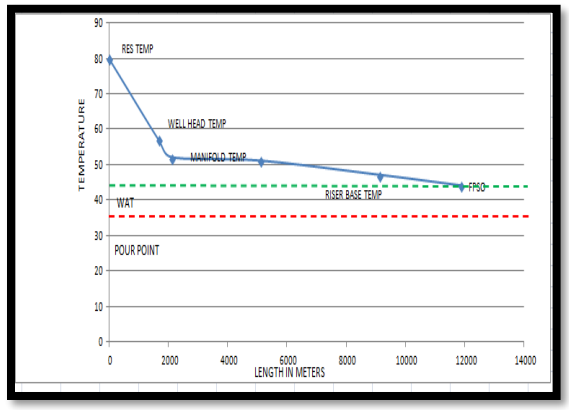

Figure 4.8.2.E: Temperature drop from Reservoir to FPSO

An U value of 2 Btu/hr/ft2/0F tubing, 0.6 Btu/hr/ft2/0F in the jumper/ infield flow line part from well head to Manifold and 0.6 Btu/hr/ft2/0F for the flexible riser from riser base to FPSO has been considered for the purpose of study. The sensitivity on passive insulation only on the rigid flow lines from the manifold to the riser base has been carried out with U values of (0.6/0.4/0.176 Btu/hr/ft2/0F) under the steady state condition. The resultant temperature profile for peak rate, midlife is as below:

Year 2

2nd year		0.6	0.4	0.176	0.1
res	0	80	80	80	80
well head	1670	57	57	57	57
M1	2120	52	52	52	52
M2	5120	47	48	51	51
riser base	9120	38	42	47	48
FPSO	11870	36	39	44	46

Table 4.8.2.C: Temperature Profiles for various U Values in Btu/hr/ft2/0F for year 2

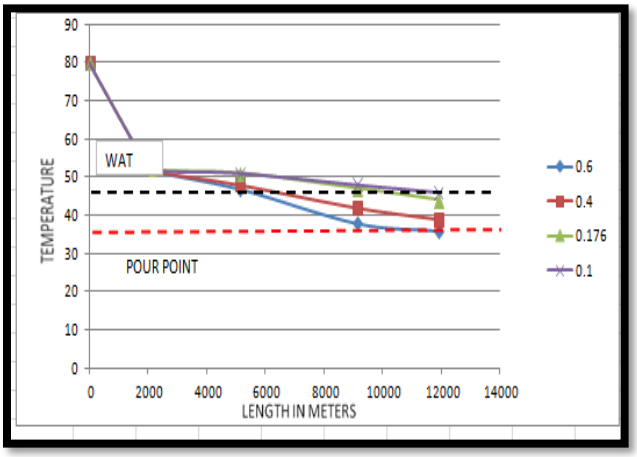

Figure 4.8.2.F: Temperature drop for various U Values in Btu/hr/ft2/0F for year 2

Year 6

6th year		0.6	0.4	0.176	0.1
res	0	80	80	80	80
well head	1670	60	60	60	60
M1	2120	51	51	51	51
M2	5120	50	51	53	54
riser base	9120	42	45	49	51
FPSO	11870	40	43	47	49

Table 4.8.2.D: Temperature Profiles for various U Values in Btu/hr/ft2/0F for year 6

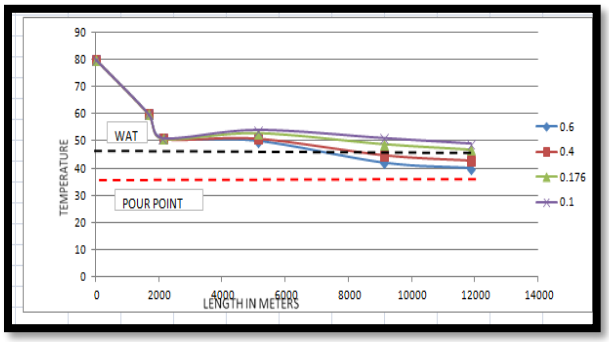

Figure 4.8.2.G: Temperature drop for various U Values in Btu/hr/ft2/0F for year 6

Year 10

10th year		0.6	0.4	0.176	0.1
res	0	80	80	80	80
well head	1670	57	57	57	57
M1	2120	51	51	51	51
M2	5120	45	47	49	50
riser base	9120	36	40	45	47
FPSO	11870	34	38	43	45

Table 4.8.2.E: Temperature Profiles for various U Values in Btu/hr/ft2/0F for year 10

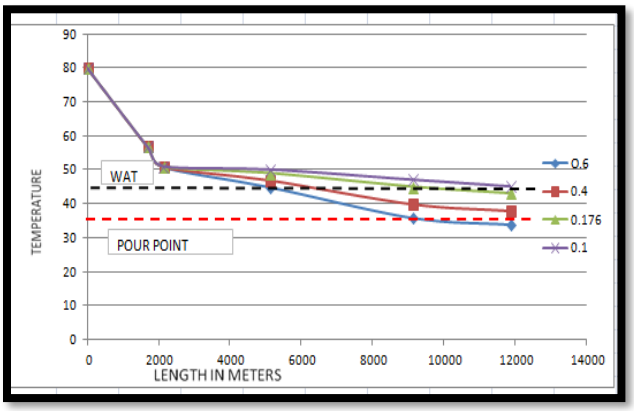

Figure 4.8.2.H: Temperature drop for various U Values in Btu/hr/ft2/0F for year 10

Year 12

12th year		0.6	0.4	0.176	0.1
res	0	80	80	80	80
well head	1670	54	54	54	54
M1	2120	51	51	51	51
M2	5120	43	45	47	48
riser base	9120	34	38	43	46
FPSO	11870	32	36	41	44

Table 4.8.2.F: Temperature Profiles for various U Values in Btu/hr/ft2/0F for year 12

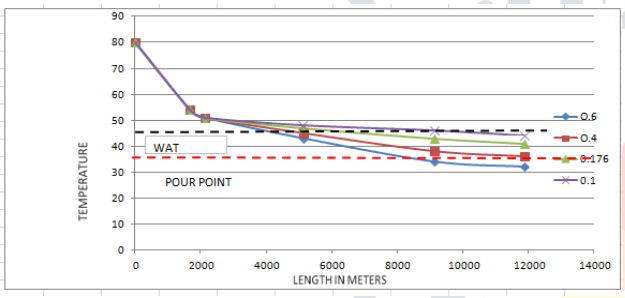

Figure 4.8.3.I: Temperature drop for various U Values in Btu/hr/ft2/0F for year 12

From the above plots during we observe that the overall heat transfer coefficient of 0.176Btu/hr/ft2/0F is found to be optimum to get the well fluid arrival temperature to be above the WAT at FPSO for the most of the profile period. The overall heat transfer co-efficient that is optimized from the simulations can be achieved by passive insulation.

There are three types of passive insulation, namely, wet and dry insulation, and pipeline burial.

A typical dry insulation scheme can be achieved by a pipe-in-pipe (PIP) configuration. The materials used between the outer jacket and pipeline include low-density foam such as rock wool and polyurethane, which have a U-value of approximately 1 W/m^{2}K.

Insulation Type	U-Value (Btu/hr–ft^2–°F)	U-Value W/m^2–K
Solid polypropylene	0.50	2.84
Polypropylene foam	0.28	1.59
Syntactic polyurethane	0.32	1.81
Syntactic polyurethane foam	0.30	1.70
PIP syntactic polyurethane foam	0.17	0.96
Composite	0.12	0.68
PIP high efficiency	0.05	0.28
Glass syntactic polyurethane	0.03	0.17

Table 4.8.2.G: Typical performance of insulated pipeline

The table mentioned above shows the various insulation types and the insulation materials that are used. The overall heat co-efficient value of 0.176 Btu/hr-ft^2-F can be obtained by PIP syntactic polyurethane foam.

The likely arrival temperature profiles at various nodes (A2-M1, A2-M2, RISER BASE &

FPSO) during steady state with overall heat transfer coefficient of 0.176Btu/hr/ft2/ °FOver the profile period are depicted in the plot below.

years	M1	M2	riser base	FPSO
1	50	50	50	43
2	52	51	47	44
3	52	52	48	45
4	52	52	48	46
5	52	53	49	47
6	51	53	49	47

7	51	54	50	48
8	52	54	50	48
9	51	52	48	46
10	51	49	45	45
11	51	47	43	43
12	51	47	43	43

Table 4.8.2.H: Temperature profiles at various nodes

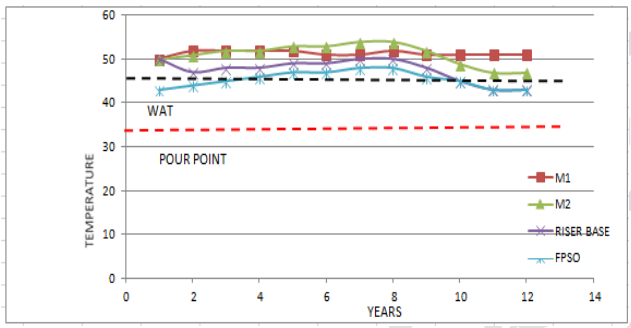

Figure 4.8.2.J: Temperature profile for M1, M2, Riser base & FPSO

The arrival temperatures at FPSO are above the WAT temperature from 5th year to 8th year. During the initial four years and last four years the well fluid arrival temperature is around 42℃ which is just equal to the live oil WAT against the safe limit of dead oil WAT (47℃) considered as basis for the study.

The arrival temperatures at riser base are above dead oil WAT (47℃) for initial 8 years and falling below dead oil WAT for the last three years of the profile period. It can also be seen that there is 3 to 7℃ temperature drop from riser base to FPSO over the entire profile period. From 9th year onwards the arrival temperatures at FPSO can be further improved by flowing the well fluids through single line and the likely arrival temperatures for 9th, 10th,11th and 12th year are 47℃, 45℃ and 44℃ respectively and at riser base the arrival temperatures are further 3 to 6℃ higher than at FPSO during the same period. Also during the fag end period wax related issues due to lower arrival temperature may not be a concern as the envisaged water cut in the profile is around 60% , due to which the flow pattern would be more of oil in water than water in oil, so deposit amount decreases as the emulsion water cut increases. High levels of water alone may maintain the system in a water-wet state.

Year wise	Riser Base Temperature(℃)	FPSO Temperature(℃)
2027-28	50	48
2028-29	47	46
2029-30	46	44
2030-31	46	44

Table 4.8.2.I: Temperature profiles obtained in FPSO and Riser Base from 9th year to 12th year using single lines

Year wise	Water Cut (%)
2027-28	49
2028-29	54
2029-30	57
2030-31	60

Table 4.8.2.J: Water Cut profiles from 9th year to 10th year.

The arrival temperatures of the well fluids at FPSO can be maintained above dead oil by following means.

- Electrically Heated Risers: As it is noted that the fluid temperatures are above WAT upto the riser base use of electrically heated flexible risers from seabed to FPSO would enable the well fluids from reaching FPSO above WAT.
- Vacuum Insulated tubing (VIT): Application of VIT in the tubing would facilitate in higher tubing head temperatures (plus 6℃ gain) and consequently higher arrival temperatures at FPSO.

The temperature at the sources and FPSO after applying Vacuum Insulated Tubing with an overall heat transfer co-efficient value of ~ 0.01BTU/hr/ft2/F are given below

Year	X2	X2 A	X2 B	X2C	X2 D	X2 E	FPSO
2019-20	63.3	63.9	64.1	64.0	63.6	62.8	52
2020-21	61.6	64.7	63.1	63.1	63.0	63.0	52
2021-22	61.9	66.6	61.9	61.8	62.6	63.0	52
2022-23	62.0	67.1	61.5	61.6	61.2	62.9	52
2023-24	63.1	67.0	61.1	61.0	61.1	62.7	53
2024-25	64.4	66.7	61.3	61.3	60.8	62.3	53
2025-26	64.8	65.9	62.9	64.6	59.9	71.0	54
2026-27	64.8	64.9	64.5	65.5	59.9	72.0	54
2027-28	64.7	63.9	64.7	65.4	61.7	73.0	53
2028-29	64.8	63.7	64.6	65.0	63.8	73.0	52
2029-30	64.6	63.5	64.4	64.9	65.1	73.0	50
2030-31	64.5	63.2	64.4	64.9	65.6	73.0	50

Table 4.8.2.K: Temperature at the sources and FPSO by VIT

- Passive insulation: Application of specialized insulation material for flow line from manifold to riser base by achieving higher heat transfer coefficient values.
- Electrically Heated Flow lines: Use of Electrically heated flow line systems like the skin heat tracing, Trace heating systems for the flow line from manifold to riser base would enable in maintaining the well fluid temperature at the desired levels.

Summary

- The arrival temperatures at FPSO are above the WAT temperature from 5th year to 9th year and falls below the dead oil WAT for initial four years and fag end.
- The arrival temperatures at riser base are above dead oil WAT (47℃) for initial 10 years and falling below dead oil WAT for the last two years of the profile period.
- Electrically heated flexible risers from riser base to FPSO and infield flow lines/jumpers from well head to manifolds can be used to maintain the arrival temperatures of the well fluids at FPSO above the WAT (47℃) throughout the profile period.
- From the flow hydraulic study it is observed that major part of the well fluids from X2-E wells can flow as per profile rates.
- Well X2-B & X2-C tubing head pressures are inadequate from 5th year to 9th year, similarly tubing head pressures of X2 is inadequate from 9th and 10th, X2-D is adequate from 10th and 11th year and well X2-A from 6th year to 9th year .
- During this profile period for the respective wells artificial lift is required. Production can be maximized during these years through gas injection.

4.8.3 ARTIFICIAL LIFT REQUIREMENT

Vertical Lift Performance study and After Bean Studies of the oil wells indicate that 5 wells X-2, X2-A, X2-B, X2-C and X2-D are unable to flow from the manifold to the FPSO considering 10kg/cm^2 arrival pressure at FPSO from mid to late profile period and thus require artificial lift to supplement the reservoir energy.

From the table below we observe that the After Bean Pressure arrived at each well head is generally less than Tubing Head Pressure. But during the midlife till late profile period the After Bean Pressure considering 10Ksc arrival pressure is greater than the Tubing Head Pressure. During this period artificial energy is required.

Year	X2	X2 A	X2 B	X2C	X2 D	X2 E
2019-20	25.6	25.5	30.5	30.9	25.7	21.4
2020-21	31.7	31.3	35.8	36.1	31.8	24.4
2021-22	31.6	31.2	35.9	36.2	31.7	24.2
2022-23	32.3	31.9	36.3	36.7	32.5	24.8
2023-24	32.8	32.5	36.1	36.3	33.3	24.9
2024-25	31.5	31.0	34.3	34.5	31.6	24.2
2025-26	30.7	30.1	33.6	33.9	30.6	24.0
2026-27	32.0	31.2	34.9	35.2	32.0	23.9
2027-28	29.7	29.0	32.4	32.8	29.6	21.7
2028-29	26.6	26.2	29.0	29.7	26.4	20.0
2029-30	23.8	23.5	26.0	26.9	23.6	18.8
2030-31	23.2	22.9	25.3	26.5	22.9	17.9

Table 4.8.3.A: ABP generated by 10 Ksc arrival pressure at FPSO

Note: Red font indicates ABP>THP

ESP and Gas Lift are the main lift modes used in deep water. Due to high GLR in the wells ESP is not likely to perform satisfactorily. Gas lift is the preferred artificial lift method in the subsea completed wells due to the availability of gas.

The well wise average injection gas requirement over the profile period has been calculated in software is tabulated below considering 40 Ksc as the outlet pressure:

Table 4.8.3.B: Well wise injection rate

Comparing the After Bean Pressure and Tubing Head pressure an outlet pressure of 40 Ksc is considered. The likely tubing head pressures and temperatures with gas lift are tabulated below for different fields. Injection gas temperature at subsea wellhead considered: 25℃.

WELL NAME	YEAR	GI RATE mmscmd	GI DEPTH	THP
X2	2026-27	0.16	1600	40
	2027-28	0.15	1600	40
X2 A	2024-25	0.15	1500	40
	2025-26	0.15	1500	40
	2026-27	0.15	1500	40
	2027-28	0.012	1500	40
X2 B	2023-24	0.14	1400	40
	2024-25	0.14	1400	40
	2025-26	0.13	1400	40
	2026-27	0.15	1400	40
	2027-28	0.15	1400	40
X2 C	2023-24	0.16	1400	40
	2024-25	0.15	1400	40
	2025-26	0.15	1400	40
	2026-27	0.15	1400	40
	2027-28	0.15	1400	40
X2 D	2025-26	0.17	1550	40
	2026-27	0.15	1550	40

	X2	X2 A	X2 B	X2C	X2 D	X2 E
2019-20	129	132	121	121	124	130
2020-21	115	100	84	87	100	104
2021-22	96	71	60	63	81	84
2022-23	82	53	39	50	68	75
2023-24	62	36	40	40	66	68
2024-25	50	40	40	40	54	58
2025-26	35	40	40	40	40	47
2026-27	40	40	40	40	40	36
2027-28	40	40	40	40	31	27
2028-29	27	30	32	32	29	21
2029-30	28	31	33	34	26	26
2030-31	30	32	35	36	25	20

Table 4.8.3.C: Tubing Head Temperatures after gas lift

	X2	X2 A	X2 B	X2C	X2 D	X2 E
2020-21	37.9	40.2	40.5	36.8	37.5	27.1
2021-22	36.6	35.9	39.4	39.7	37.1	26.6
2022-23	37.9	37.4	41.2	44.5	37.5	25.7
2023-24	38.2	37.6	41.0	41.0	38.9	27.2
2024-25	36.6	35.9	38.7	38.9	36.7	26.4
2025-26	36.3	35.2	39.0	39.5	36.1	26.1
2026-27	38.2	37.1	40.5	41.1	38.2	26.3
2027-28	36.0	35.2	38.4	39.3	36.1	24.6
2028-29	33.3	32.7	35.8	37.1	33.1	23.0
2029-30	32.2	31.8	35.1	37.3	31.9	22.8
2030-31	37.9	37.4	41.2	44.5	37.5	25.7

Table 4.8.3.D: ABP after gas lift

Without gas lift the total liquid rate for the profiles~ 46079 sm^3/day. With gas lift the total liquid rate for the profiles~ 90096 sm^3/day. Nearly 93% of the profile can be recovered by gas injection.

Summary

- Out of total 6 oil wells, 4 wells require artificial lift to meet the profile rates.
- Gas lift is the lift mode of choice for the field.
- The peak optimized gas injection rate per well is as follows:

  X2~0.15 mmscmd

  X2 A~0.012-0.15 mmscmd

  X2 B~ 0.14 mmscmd

  X2 C~0.15 mmscmd

  X2 D~0.15 mmscmd
- Total 0.75 mmscmd of injection gas is required for the X2 field.
- Most of the profile (~93%) can be recovered with gas injection.

4.8.4 CHOKE SIZE SELECTION

A choke is a restriction in a flow line that causes a pressure drop or reduces the rate of flow. A wellhead choke controls the surface pressure and production rate from a well. Wellhead chokes are used to limit production rates to meet surface constraints, protect surface equipment from slugging, avoid sand problems due to high drawdown, and control flow rate to avoid water or gas coning. Placing a choke at the wellhead increases the wellhead pressure and, thus, theflowingbottomhole pressure which reduces production rate.

As we observe in the first 6 years of X2, X2 D, X2 E wells and first 4 years of X2 A, X2 B, X2 C wells the tubing head pressures are very high. The FPSO pressure is at 10 Ksc. So we need to choke down the tubing head pressure to a reasonable value. From the

After Bean Pressure and Tubing Head Pressure profiles we decide the outlet pressure to be 40 Ksc.

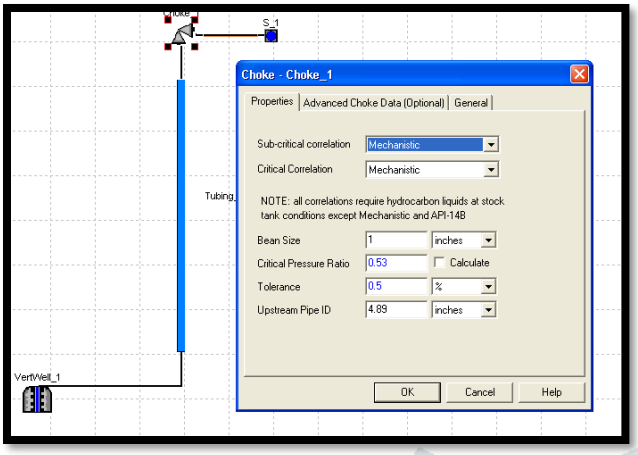

Figure 4.8.4.A: Bean Size selection in pipesim

The graph below denotes the pressure around 128 Ksc is choked down to 40 Ksc

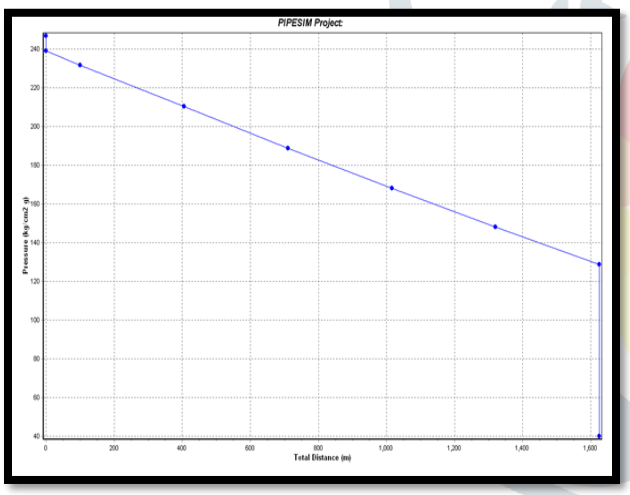

Figure 4.8.4.B: Pressure reduction by application of choke

So the bean sizes (inches) required for the wells in their respective years is tabulated below.

Year	X2	X2 A	X2 B	X2C	X2 D	X2 E
2019-20	0.44	0.42	0.441	0.43	0.43	0.43
2020-21	0.76	0.72	0.78	0.75	0.72	0.73
2021-22	0.81	0.805	0.948	0.913	0.78	0.8
2022-23	0.86	1.01		1.25	0.869	0.7
2023-24	1.03				1	0.925
2024-25	1.35				1.28	1.12
2025-26						

Table 4.8.4: Well wise required Bean sizes

Summary

- First few years of the production, the tubing head pressures of the wells are very high. So it is decided to choke down the pressure.
- The bean size required for X2, X2 A, X2 B, X2 C, X2 D, X2 E wells is ranging from 0.75 to 1.3 inches.

4. SUMMARY AND CONCLUSION

- The importance of flow assurance has increased in case of deepwater development due to lower sea bed ambient temperature, higher flowing pressures, remote locations and great water depths, longer sub-sea tie back distances, larger riser height and higher external hydrostatic pressure. When proper care of these issues is not taken at design stage possibility of solids deposition i.e. paraffin waxes and asphaltenes coming out of solution, formation of hydrate plugs etc exists leading to restrictions and blockages in well bore, flow line, risers and process facilities.

- Flow assurance problems encountered in multiphase hydrocarbon production systems include:Hydrates, Wax, Asphaltene, Slugging, Erosion, Corrosion, Emulsion, Scaling.

- The Flow Assurance for a deepwater field in east coast of India having 5 oil wells been carried out. Depth ranging from around 600 meters to 1000meters. Clustered development with subsea tie back to a centrally located FPSO has been considered.

- The vertical lift performance has been carried out for all the wells for tubing size optimization. X2, X2 A, X2 B, X2 C, X2 D wells require 5.5" and for X2 E well 4.5" tubing is adequate.
- Flow hydraulics have been carried out to find the optimum flow line size from subsea manifolds to FPSO. 10" dia dual line flow line has been found optimum considering life of field operation with minimum arrival pressure of 10 ksc at FPSO.
- From the temperature profiles generated from the simulations, the arrival temperatures of well fluid at FPSO are above the WAT during 5th year to 8th year's field life and below WAT during the remaining profile period.
- Electrically heated flexible risers (from riser base to FPSO) and infield flow lines/jumpers (from well head to manifolds), Vacuum Insulated Tubing can be used to maintain the arrival temperatures of the well fluids at FPSO above the WAT (47℃) throughout the profile period.
- The wells have adequate tubing head pressure to flow on self as per profile rates. However pressure is not adequate in some wells during certain period which can be maximized through artificial lift.

- Vertical lift performance and Flow hydraulics study indicate that 5 nos. wells X2, X2 A, X2 B, X2 C, X2 D are having inadequate tubing head pressures during midlife of the production profile, while X2 E well is likely to flow on self from the wellbore to FPSO for the entire profile period.
- Gas lift is proposed as an artificial lift method in the subsea completed wells due to the robustness and availability of gas with a optimized gas injection rate of 0.14~0.18mmscm. Most of the profiles (~93%) can be recovered against the profile rate with gas injection.
- In the initial years the tubing head pressure of the wells are very high. So there is a necessity to choke down the tubing head pressure in order to decrease the pressure loss which will in turn the production rate. The likely bean sizes found from the simulation ranges from 0.8~1 inch diameter.

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